SPE/Petroleum Society of CIM 65473

Rejuvenating Production in Brown Fields with Horizontal Sidetracks

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This paper was prepared for presentation at the 2000 SPE/Petroleum Society of CIM International Conference on Horizontal Well Technology held in Calgary, Alberta, Canada, 6-8 November 2000.

Abstract

Horizontal sidetracks offer a very viable technique for rejuvenating production in the redevelopment of brown fields. In brown fields where significant reserves exist, but occur as scattered pockets of by-passed oil, or in stacked reservoirs, their development with new wells will hardly satisfy economic screening criteria. The abundance of old wells that have drained the recoverable reserves in their drainage area and are either producing at very low rates or are closed-in, make horizontal sidetracks a viable tool for rejuvenating production and maximising existing assets.

With a vision to improve production in SPDC by 60% in 2004 and by over 200% (to 2.5 MMbopd) in the year 2010, producing the limit or sweating the existing brown fields is now a key factor. Most new wells are now horizontal completions, due to their higher productivity over vertical or inclined wells. This paper presents the benefits of horizontal sidetracks as a productivity improvement tool that was used to boost production from Obigbo North (one of SPDC-E brown fields) by more than 10,000 BOPD in 1999 alone. It discusses production gains, geology, well construction, completion types, environmental benefits and petrophysical data acquisition and interpretation problems that could be encountered with horizontal sidetracks in brown fields, based on our experience.

Introduction

SPDC operations started in the late 50's from the acreage in the Land Area Team. Most of the oldest SPDC wells and fields are therefore situated in the land area. There are still some significant amounts of recoverable reserves either bypassed or unswept in most SPDC's brown fields. Some 46 % of the wells are closed-in for various reasons mainly HGOR, HBSW, low production rates and High Sand cuts, while some 75% of the drainage points produce under 500 bopd.

Up to 20% of reported undeveloped reserves i.e. some 500 MMstb out of 2.5 MMMstb are in reservoirs that make proposals for their development rank low in current portfolio of activities. The stacked reservoir scenario is further compounded by the fact that most of these target reservoirs are overlain by reservoirs that have been depleted by past production activities. This therefore complicates wellbore hydraulic issues when drilling through them due to the severe mud losses encountered.

To develop these reserves optimally and economically, there is the need to access them with minimum additional land take and cost while isolating the shallow depleted zones and troublesome shales. Obigbo North field discovered in October, 1963 is one of such brown fields of SPDC East.

Application of Horizontal Sidetracks in 1998 and 1999 allowed us get around most of the challenges presented by the above scenarios, This boosted production by more than 10,000 bopd and delivered wells at much lower costs by:

(i)Eliminating the need for new land, drilling of surface holes as well as setting surface casing thereby harnessing the attendant gains.

(ii)Reducing the total footage drilled by starting the window as deep as possible in the old well with impact on rig time, waste management etc.

(iii)Isolating the depleted zones and troublesome shales with the old casing thereby allowing trouble free access to desired zones.

Obigbo North Field

The Obigbo North field is located some 18km north-east of Port Harcourt and straddles OML's 11 and 17 (fig.1). The field was discovered in October 1963 by exploratory well Obigbo North-1 and covers approximately 50 km^2. The exploration well was drilled on the main accumulation of the Obigbo North field and encountered hydrocarbons between 6,540 and 10,000 ftss. The field contains 66 reservoir blocks, of which 55 are oil bearing and 11 are gas bearing. Except for the E6.0 and deeper reservoirs, which contain light oil the average reservoir contains medium gravity (API=26^o, Rsi 300 to 400 scf/stb) oil.

Field Structure

The Obigbo North oil field lies astride a major south hading growth fault as a series of faulted rollover anticlines with smaller footwall closures. The field is structurally complex, consisting of seven structural closures contained within three major fault blocks (Fig.2).

The primary Obigbo North structure is a low relief rollover anticline that formed in the hanging wall of the main bounding fault A. The C9.0/9.4 reservoir is a simple rollover feature with 2 unequal dip-closed culminations. Hydrocarbons are encountered in the main A block.

The general structural picture of the D2.3, D6.0, D9.0 and E7.0 is similar to those described in section above. The main differences are in the main A block where the smaller, eastern culmination gradually disappears. Instead a different culmination grows to the south of the main culmination of the A block.

Production Overview

To date, the field has been developed by 51 wells, with a total of 98 drainage points. Oil production from the field commenced in October, 1965. After a short period of peak production of 40 Mstb/d in 1967, a decline in the total field production was observed (fig.3). This can be attributed to high GOR and BSW developments in the field giving rise to vertical lift problems.

The bulk of the production has come from three reservoirs (C9.4A, D1.3A, and D9.0A). All the reservoirs produce naturally or with gas lift, except for the D1.3A. Water injection was initiated in the D1.3A reservoirs as a pilot project in 1974 with full scale injection commencing in 1978.

From 1992 - 1996, 3D seismic data was acquired and interpreted over the field and a 3D based full-field reservoir simulation models were constructed for the C9.0/C9.4A and D1.0/D1.3A reservoir complexes as part of the Obigbo North field Review/Field Development Plan. The results of the above studies and an update of the reservoir simulation models of the C9.0/C9.4A and conventional reservoir engineering studies of the D2.3A, D6.0, D9.0A and E7.0 reservoirs formed the basis of the final Obigbo North Field Review. In January 1998, a drainage point review was undertaken to further harmonise and fine-tune the recommendations of previous studies. The drainage points review showed that, of the 72 drainage points in the field as at January 1998, only 1 drainage point produced above 2000 bopd, 6% produce between 1000 and 2000 bopd, 12% produce between 500 and 1000 bopd, 25% produce between 100 and 500 bopd while 56% were closed in due to various reasons including HGOR, HBSW, low production rates and High Sand cuts. (Fig-4). It summarised that four horizontal sidetracks be drilled to deliver a combined initial potential of 9,600 Mbopd and additional developed reserves of 23.4 MMstb from the C9.0/C9.4 complex, D2.3 and E7.0 reservoirs. At the end of the exercise, Obigbo North 20 was identified for a horizontal sidetrack into the E7.0 reservoir, well 50 for horizontal sidetrack into the D2,3 reservoir while wells 38 & 10 were identified for sidetracks into the C9.0/C9.4 reservoirs. The sequence for the sidetracks started with well 20, followed by well 38, well 10 and well 50.

Well construction:

The sidetracks were drilled with Deutag T-26 (2000 HP drilling rig) and Deutag T-6 (800HP workover rigs). The processes used to drill the sidetrack with the two rigs were the same and could be adopted for lighter rigs too. The major driver for the process cycle adopted for well construction was cost reduction. The process undertaken in the well construction involves: (Fig.5)

1. Abandon existing completion.

The sidetrack candidates in the Obigbo North field were wells, which were originally dual completions on two or three intervals of varying reservoir pressures and fluid characteristics. Consequently the major challenge in the abandonment of existing completions were (1) proper zonal isolation (2) successful retrieval of old corroded completions tubing and accessories (3) creating a proper bore for the side track to be initiated.

A simple fail proof method was employed to achieve the objectives above. The existing completion tubing was used to squeeze off the producing intervals employing carefully engineered cement recipes. Thereafter the tubing was cut above the dual packer and a 500ft cement plug was set above the packer - this ensures at least two mechanical barriers across the abandoned intervals (fig 5). The strategy of cutting and retrieving old completion above the dual packer was standardised thus improving historical fishing success rates from under 40% to 100%.

2. Casing Exit

In the Obigbo sidetrack project, window cutting and casing exit was carried out using the traditional Baker whipstock combined with window-master. This was done in one run by incorporating an orientation (UBHO) sub to facilitate the use of gyro survey for proper orientation prior to cutting the window with the 'window-master'. This step of the operation was the critical success factor for the rest of the well construction phase i.e. ensuring that a proper window was cut - linking the parent wellbore with the new sidetrack. Typically, a whipstock was set on a cement plug at a predetermined position in the original casing. The window was cut using the window-master metal muncher in tandem with the melon mills for dressing the cement window.

3. Build-up section

Being a brown field, the major challenge was the stuck pipe and loss circulation hazards presented by drilling in stacked depleted reservoir scenarios. A pseudo oil based mud (POBM) system was used to maximise lubricity of the hole, prevent free water from destabilising the interbeded shales and to minimize impairment of the reservoirs. The 6" or 8-1/2" build up section were long radius drilled at a build-up-rates of 4-6deg/100ft. High and low viscosity sweeps were used for hole cleaning and cuttings transport

4. Horizontal section
After drilling the drain hole, the completion liner was deployed with drillpipe, hung off with liner hanger and cemented to the shoe of the intermediate casing with the External Casing Packer (ECP). This system allows stage cementing while maintaining a through bore to the reservoir without having to drill or clean out cement from the completion string.

5. Well Completion & Cleanup
Evaluation of the C9.0/C9.4, D2.3 and E7.0 reservoirs for sand with sand prediction tool 'FIST' indicated possibility of sand failure in the C9.0/C9.4 and D2.3 while the E7.0 formation is consolidated and require no sand control. Accordingly, the C9.0/C9.4 and the D2.3 drain sections were completed with 4-1/2" strataPac screens while the E7.0 drain section was completed with predrilled liner.

Underbalanced clean up using coiled tubing was employed to cleanup the drain section. The mud in the horizontal sections were first displaced to brine to break the dynamic equilibrium between the filter cake and mud system and allow direct contact of the foamed acid with the filter cake. The filter cake of the POBM is formed by the polymer and Calcium Carbonate components of the mud. The cake behind the liners required treatment recipe that would dissolve inorganic Calcium Carbonate, the organic asphaltene as well as break the long chain polymers. With these objectives in mind, a 'One-Shot Acid Plus' recipe was provided by BJ Services. The recipe is a dispersion of an aromatic solvent and an aqueous acid, plus some special surfactants and an inhibitor. The aromatic solvent disperses and partially dissolves solid asphaltic and paraffin residue of the cake, which then permits the aqueous acid to react with the remaining acid soluble compounds. Nitrogen gas, adequate for 65% foam quality would be introduced and the resultant foam mixture was then squeezed uniformly across the liner while withdrawing the coil tubing from the toe to the heel of the horizontal section. The spent acid and remnants of the mud cake were produced once the well is opened to flow due to the underbalance.

Waste Management
Waste management was a major issue in the Obigbo Sidetrack campaigns since most of the locations were located in built up residential area operations had to be 'lean and green'. The waste generated can be classified into two. 1) Solid drilled cuttings 2) Liquid waste/effluents. These were slurified and injected into dedicated injection wells and the rest were stored in lined corals for bio-remediation. The liquid waste was also injected. Legislation require that the injections wells be monitored from three satellite water wells on a continuous basis which is being done. Domestic wastes were segregated and incinerated.

Obigbo North-20 Sidetrack in the E7.0 reservoir
The E7.0 is an oil and gas bearing sand with an average gross thickness of 130 ft. Sidewall samples of the E7.0 sand reveal it to be a fine to very fine grained sand with some medium and coarse grained layers.

Based on log signatures, the E7.0 is interpreted to be shoreface deposit that has relatively uniform reservoir properties, with a few baffles and internal barriers that could reduce connectivity and limit flow. The homogeneity of the reservoir is expected to yield a significantly high kv/kh which unfortunately result in a higher likelihood of gas and water coning within the reservoir. The thickness of the original oil column, the potential for coning problems and the relative uniformity of the reservoir properties made the E7.00A reservoir and ideal candidate for horizontal completions.

The non-movement of the GOC since exploitation and only 3 ft upward movement in OWC suggested that the reservoir had a strong water drive and does not require pressure maintenance is required. Based on evaluated undeveloped reserves of 14.3 MMstb, three horizontal developmental well were suggested to drain the remaining reserves in the E7.0A reservoir. However based on economics, it was recommended to reduce the economic risks before drilling more than one horizontal well into it.

The 1998 drainage point review of the wells in Obigbo north field identified wells 20 and 50 as possible candidates to be used for sidetrack into the E7.0 sand. Well 20 was later considered as the better of the two candidates due to its optimal position on the E7.0 structure.

Historical Overview of Obigbo North -20
OBGN-20 was initially completed as a dual string oil producer on the D1.3 and the E7.0 sands in March 1983 (Fig 6). The well produced an average total rate of 600 bopd before the onset of sand production from the D1.3 interval. Consequently, the well was re-entered in December 1985 to install internal gravel pack across the D1.3 interval. The well thereafter produced satisfactorily and had had a peak rate of 1800 bopd in September 1989. Another re-entry was done in December 1989 to rectify communication problem between the E7.0 and D1.3 introduced during a wireline job. Thereafter only the E7.0 interval produced till 1991 when it quit production due to high BSW. The D1.3 interval did not produce after the workover of 1989 and attempts to produce the interval by gaslift or nitrogen lift were not successful. The 1995 FDP recommended a repair only on the E7.0. This repair ranked low on the list of proposed workovers and did not meet SPDC economic criteria. It was found to be more economical to use well-20 to provide a horizontal drainage point in the E7.0 reservoir. The well was re-entered in October 1998 and sidetracked successfully into the E7.0 reservoir providing 610 feet of horizontal section in the E7.0 reservoir.

Although inflow and vertical lift performance results indicate higher rate can be achieved, a restricted potential of 3000 bpd has been assigned to the well pending further reservoir management information from planned production log. Evaluation of the E7.0 formation with in house tools indicated a reasonably consolidated formation. Hence the well was completed open hole with 4½" predrilled liner a 3½" tubing. External casing packers were used to isolate the E7.0 pay zone properly before cementing the blank liner in the build-up section (Fig 6). The well now produces 3500 bopd (dry) (Fig. 7)

Obigbo North-50 Sidetrack in the D2.3 Reservoir

The D2.3 reservoir consists of a shoreface sequence that has been cut by two distributary channels. The reservoir is oil productive on both sides of the "A" fault. The two culminations appear to be separated by a saddle. The reservoir has a reasonably strong acquifer drive and requires no pressure maintenance for future development.

Based on the revised volumes and material balance calculations, the STOIIP of the D2.3A was re-evaluated as 49.6 MMstb with an ultimate recovery of 24.3 MMstb. Only 6.11 MMstb of oil has been produced from the reservoir while 18.19 MMstb of the UR was yet to be produced. A horizontal drainage point was proposed to recover 12.7 MMstb of oil from the D2.3A reservoir. The subsurface location of the horizontal section was derived as a result of dynamic fluid modelling. Accordingly the drainage point review of Obigbo north field in 1998 identified well 50 as good candidate to sidetrack and provide a horizontal drain hole in the D2.3 reservoir.

Historical Overview of Obigbo North -50

The well was initially completed as a dual string oil producer on the D2.3 and E6.1 sands in January, 1991, with gaslift mandrels installed in the short string. The E6.1 sand was consolidated with Eposand-40 system from the onset. The D2.3 interval had a peak production of 1273 bopd in December 1991 with an increasing sand cut trend. To forestall the increasing trend in sand, the D2.3 interval was consolidated through the tubing in January 1992. Unfortunately, the Eposand resin cured inside the tubing and prevented the well from flow after the sand consolidation job. The E6.1 interval was plague with high water and gas shortly after inception and was shut in November 1999. The two intervals completed on well 50 produced for less than a year after completion.

The well was re-entered in June 1999 and sidetracked successfully to a TD of 11,030 ftah, thus providing 1400 ft of horizontal section in the D2.3A reservoir. Two ECP's were employed to separate the StrataPac screens and isolate the drainhole, while the upper blank liner section above the ECP's was cemented. The well currently produces 3500 bopd (dry) (Fig 8)

Obigbo North-10 & -38 Sidetrack in the C9.0/C9.4 Complex

The C9.0/C9.4 complex is composed of several smaller fining and coarsening upwards sequences. No core is available over the C9.0/C9.4 complex and its description is based on the patterns and cyclicity observed from log and sidewall samples. It has an average sand thickness of 119 ft of 27% porosity.

The depositional environment of the C9.0 sand consists of delta/shoreface sands. This sand is in communication with the C9.4 reservoir, at least over portions of the main culmination, and has been considered as a complex sand with minor prograding events in a transgressive trend. The C9.0 sand consists of two distinct thin coarsening upwards sequences, the sediments are composed of very fine grained sands and heterolithics.

The implication on the flow behaviour of the reservoir is that the sand bodies of the C9.0/9.4 complex are composed of sub-units separated by laterally extensive silt stones which are likely to act as barriers/baffles. The C9.0 and C9.4 reservoirs initially had a common OOWC throughout the 'A' block. The OGOC initially seemed to be common in the main, or western, culmination. However, the eastern culmination had a different OGOC for the C9.0 and C9.4 reservoirs with that on the C9.0 being higher by 42 ft. These OGOC in the eastern culmination is about 70 ft deeper than those observed in western culmination.

In the early wells drilled in the field there was no evidence of lateral variation in the original contacts. However, RST logs ran in several wells in the "A" block 1993 revealed the presence of a tilted PGOC across the C9.0/9.4A reservoir complex. The GOC in both the C9.0 and C9.4 had receded on the western side of the main culmination with the oil having an upward movement into the gascap. This was not the case in the eastern part where the GOC had not moved. These observations, together with the simulation results show that there is medium to weak acquifer support coming from the west.

The STOIIP of the C9.0/C9.4 complex was put at 210.6 MMstb while the ultimate recovery is put at 87.8 MMstb. Only 22.7 MMstb was developed by the existing drainage points while the remaining 31.1 recoverable reserve is undeveloped. Two horizontal tracks were proposed to develop some 27.65 MMstb of the undeveloped reserves. The subsurface locations of the horizontal sections were derived from result of dynamic fluid modelling. Well 10 and 38 were selected for the sideracks.

Historical Overview of Obigbo North -10

The well was initially completed as a dual string oil producer on the D1.3 and C9.4 reservoirs in 1966. The well was re-entered to install gaslift mandrels in 1969 and to consolidate the two intervals. The D1.3 did not come in after the sand consolidation job due to declined reservoir pressure. It however began producing again from 1974 after the inception of full-scale water injection/pressure maintenance scheme in the D1.3 reservoir. The production however declined till it was closed in 1986 due to reservoir off take constraint placed on the D1.3 reservoir. The C9.4 interval came on stream in July, 1966 and produced at rates above 2,500 bopd up till November, 1970 when water production commenced and continued to increase to above 45% in 1983. The oil rate subsequently reduced drastically before the interval was closed-in in November, 1983 for low productivity.

A rig re-entry was recommended by the FDP team to repair the C9.4 and the D1.3 intervals for a recoverable reserve of 0.9 MMstb from the D1.3 and C9.4 reservoirs. The small recoverable reserves from the well made the re-entry proposal unattractive when it was subjected to economic screening. The well was re-entered in June 1999 and sidetracked successfully to a TD of 8610 ftah, thus providing 959 ft of horizontal section in the C9.0/C9.4 complex. Two ECP's were employed again to separate the StrataPac screens and isolate the drainhole, while the upper blank liner section above the ECP's was cemented. The well currently produces 2500 bopd (dry) (Fig. 9)

Historical Overview of Obigbo North -38

The well was competed as a dual string oil producer on the C9.4 and C9.0 sands. Both were closed in due to high water cut. The C9.4 interval (LS) quit production at 95% BSW in 1986 and is evaluated to have been watered out. The C9.0 interval (SS) quit production at 35% BSW in 1991. Attempts made in May 1994 to lift the C9.0 interval with nitrogen were unsuccessful. It was then recommended to re-enter the well to abandon the C9.4 interval and re-complete the well as an SSS oil producer on only the C9.0 interval. Expected oil gain was 230 bopd and a developed reserve of 1.1 MMstb was assigned to the well. The re entry ranked lowest among the proposed workover candidates in the field. The proposal to use the well for another horizontal sidetrack into the C9.0/C9.4 complex became a more economic rewarding option.

There were some reasonable uncertainties introduced from the non-uniform fluid contact movement in the complex. This was again observed when the sidetrack was landed in the C9.4. Some sections of the hole was plugged back and a pilot hole was drilled to investigate the preferential flushing observed. Petrophysical logging result of the pilot hole indicated a high probability of preferential flushing on an upper streak of the C9.4 sand. Thus indicated the unviability of the horizontal hole planned for the complex. An effort was made to acquire pressure and fluid sample with Modular Dynamic Tester (MDT) across the C9.0/C9.4 complex and was aborted due to deteriorating hole condition. A salvage option of completing the well as a dual string multiple oil producer on the C9.4, D2.3 and D9.0 reservoirs was adopted. Total production from the C9.4 and D9.0 is currently an 758 bopd. (fig 10)

Challenges:

1. Preferential flushing

Resistivity modelling was carried out to describe the log response expected from the upper member of the C9.4 reservoir, planned to be drilled by Obigbo North–38 horizontal side track (OBGN –38ST). Baker Hughes MWD DPR was modelled using offset wells data, assuming the target sand member to be fully oil bearing. When the actual logs from the well came in, showing an unexpected low resistivity response, Schlumberger AIT resistivity tools were acquired and modelled using offset wells, assuming two scenarios; one with oil water contact (OWC) present in the sand member and another without OWC. This helped to prove the unexpected: that this sand member was flushed with water, which precluded completion on the target sand. A subsequent sidetrack (appraisal) hole proved the log interpretation based on the modelling results to be correct (figure 10).

2. Drilling Problems.

A major problem encountered in drilling the Obigbo side-tracks was mud losses and lost circulation due to depleted reservoirs overlaying the target reservoirs. Thus, threats of stuck pipe by differential sticking were prevalent during the drilling operations. Measures taken to avoid jeopardising the project included.

- Using Mud with weight, enough to achieve overbalance less than 200psi to prevent differential sticking.
- At intervals, loss circulation pill mainly of graded salt pill with some soltex was blended into the active mud system to proactively stop mud losses.
- Reduced survey and connection times in order to reduce the contact time between the drill string and the wellbore.
- An optimum oil:water ratio of 70:30 was maintained in the POBM for proper hole lubricity reology.

Economic benefits:

Cost analysis show that a saving amounting to 17% of the cumulative budget, if the wells were drilled as new wells was achieved after the fourth sidetrack. However, the cost reduction trend (Fig.12) shows a significant drop as we gained more experience in sidetracking techniques. The last well OBGN-10ST was drilled at 60% of the original budget. The profitability of the sidetrack campaign was also boosted by the fact that the cumulative of 12,421 bopd generated tracked closely with planned (Fig.13); despite the salvaged well 38ST which generated only 700 bopd or 23% of the planned. Major factors that contributed to the cost savings were :

- The elimination of new surface holes and new surface casing.
- Reduced rig time spent on wells by the reduction of the total footage drilled resulting from starting the exit window as deep as possible in the old well and
- Reduced waste management cost.

The above benefits will be enhanced significantly when capable light hoist (not drilling rigs) are used for short radius sidetracks planned from Q4-2000.

Future Plan:

The successes recorded with the Horizontal Sidetracks of Obigbo North –20, -10 and –50, as well as Imo River –1 opened a new chapter in the development strategy of brown fields for SPDC. Assets on the ground, which ordinarily would have continued to lay fallow, can now be rejuvenated to provide more resources for SPDC and Nigeria. Already a multi-disciplinary team has been put together with the objective to developed some 35 bopd by Q4 2001 from existing wells that are either closed-in or producing at very low rates.

About 60% of the drainage points of SPDC's Land area is closed-in for reasons ranging from HBSW, HGOR and sand production. In addition, several producing fields have unutilised ullage in their flow station facility. It is expected that the horizontal sidetrack development strategy will therefore offer a big opportunity for lower UTC oil development.

Conclusion

Horizontal sidetrack wells have been successfully applied in the re-development of SPDC-East Obigbo north field. This has boosted production in the field by over 10,000 bopd (an increase of more than two-thirds), and developed 23.4 MMstb of additional oil reserves. In addition to maximising the use of existing assets, sidetracking from existing wells eliminated the need for acquisition of new land, thereby minimising the environmental impact. The horizontal sidetrack campaign also resulted in lower well costs.

Because Obigbo north is a brown field, differential flushing and pressure depletion in reservoirs overlying, the target reservoirs posed major challenges during the drilling operations. Also, due to the built-up environment of the field, strict environmental standards were applied in order to ensure that waste management from the drilling operation did not pose any environmental hazard.

Acknowledgement:

We wish to acknowledge shell Petroleum Development (SPDC) Port Harcourt for granting us permision to publish this paper. We are particularly grateful to 'Demola Adeyemi-Bero and Mason Oghenejobo for their steering during the job execution and in preparing this paper. We also acknowledge the contributions of David Short, Leste Aihevba, Frankline Ebomah, Dan Agbaire, Ben Osiagbovo, Muyiwa Esho, Pieter van Der Heuvel, Jon Cohen, Francis Ilesanmi, OKV, Wood, Mojeed Ali, Abdulsatter Al-murshidi, TC. Okoro, Andrew Ogununsola and the development / well engineering team. Without their participation, the campaign might not have come to fruition. Finally, we appreciate the effort and contribution of Ike Orunta for reviewing this paper.

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Legend:

MWD	=	Measurement while drilling
OWC	=	Oil water contact
UTC	=	Unit technical cost
Mmbopd	=	Million barrel of oil per day
HGOR	=	High GOR
HBSW	=	High BSW
OBGN	=	Obigb North
POBM	=	Pseudo oil base mud.

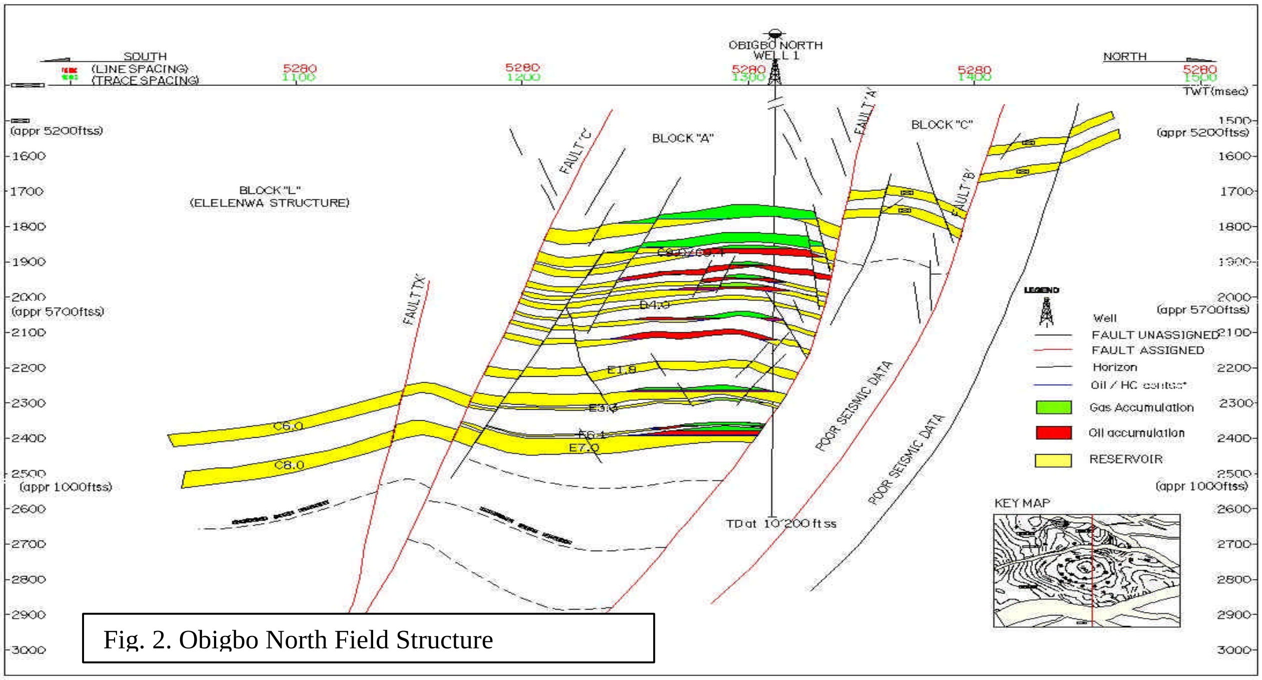


Fig. 2. Obigbo North Field Structure

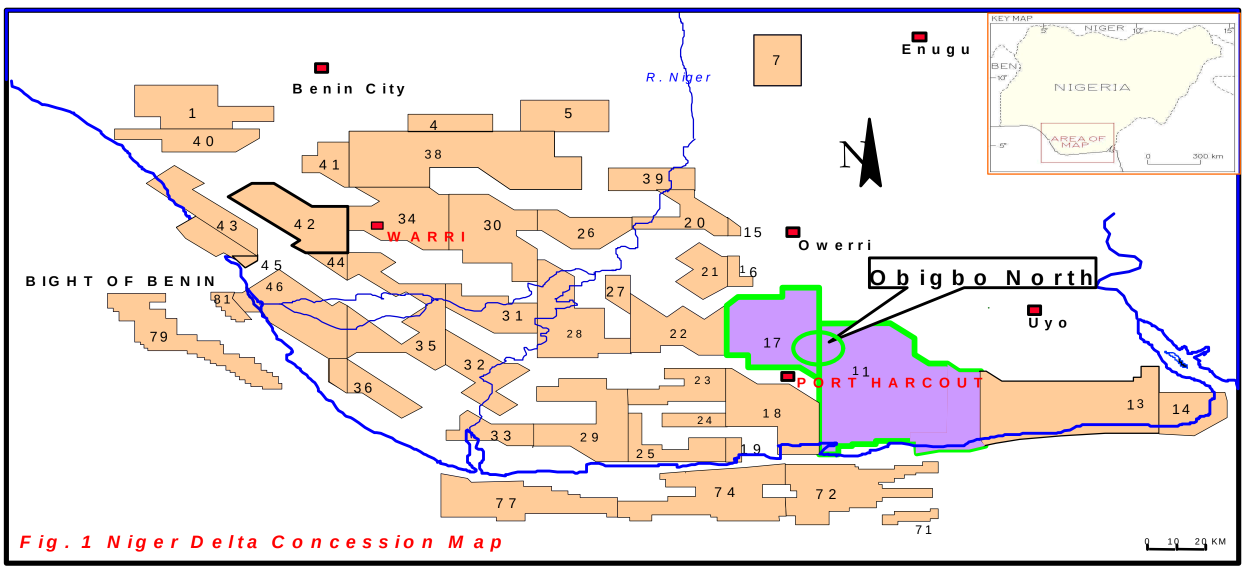


Fig. 1 Niger Delta Concession Map

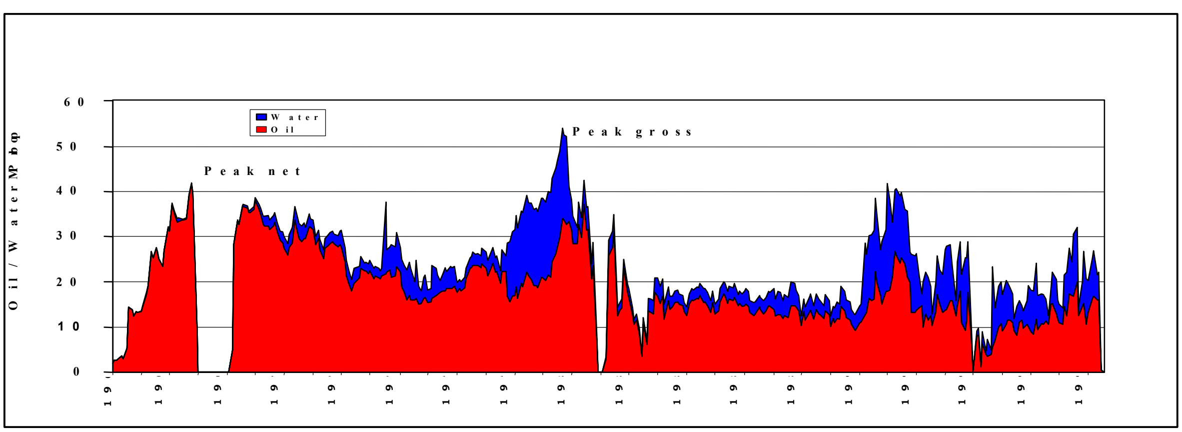
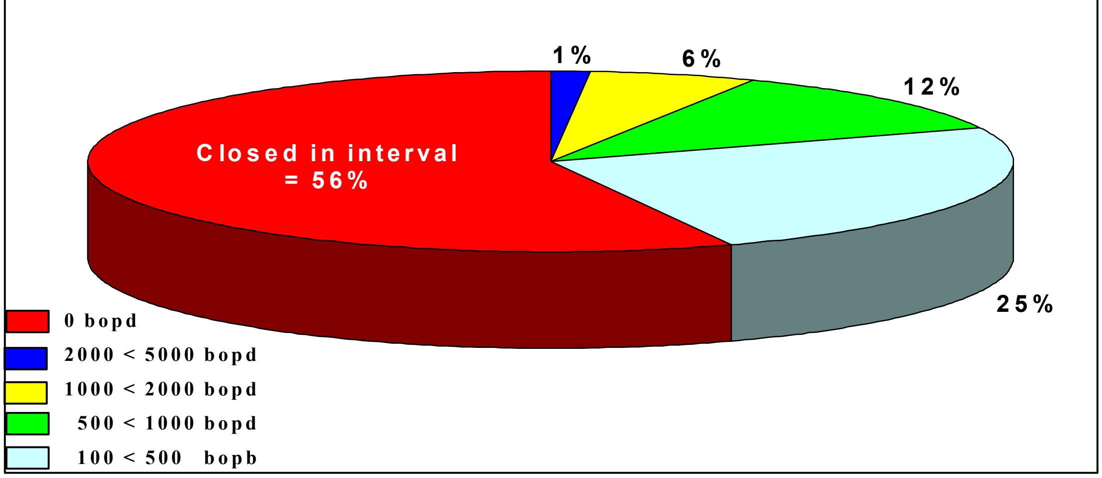


Figure 3. Production History of Obigbo North Field.

Figure 4. Drainage point Summary of Obigbo North Field @ 1/1/99



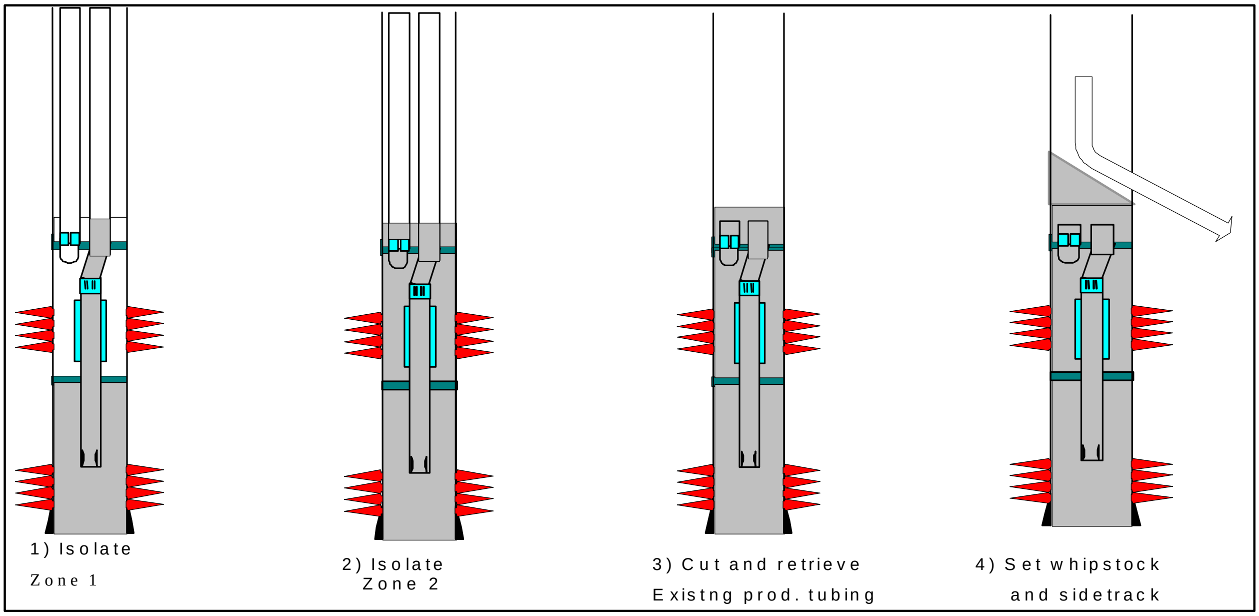


Figure 5. Horizontal Sidetrack Process

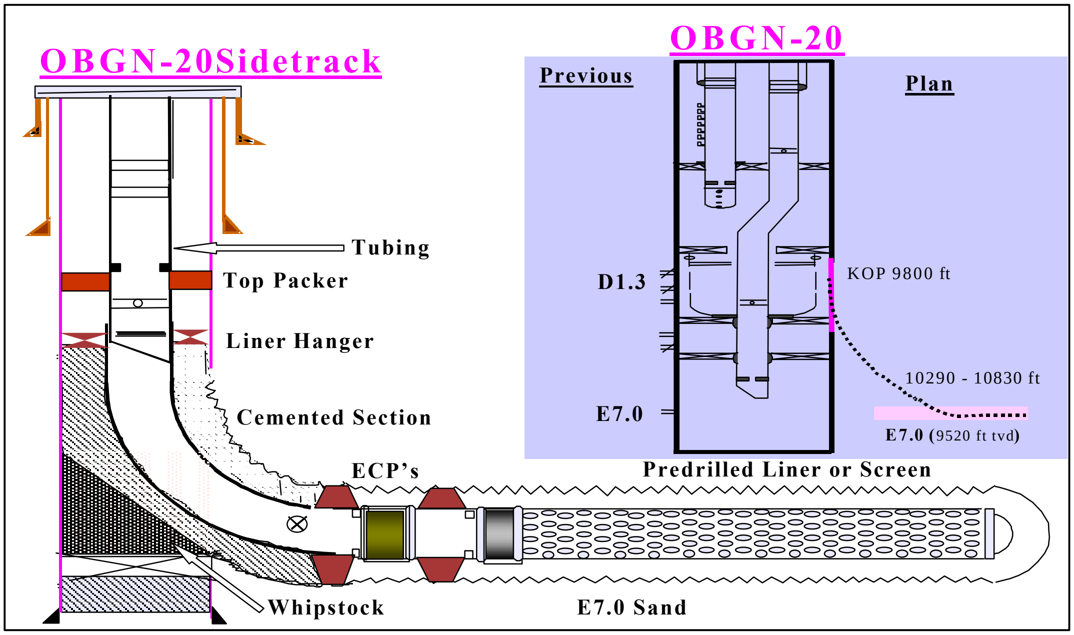


Figure 6 Obigbo North 20 Horizontal Sidetrack

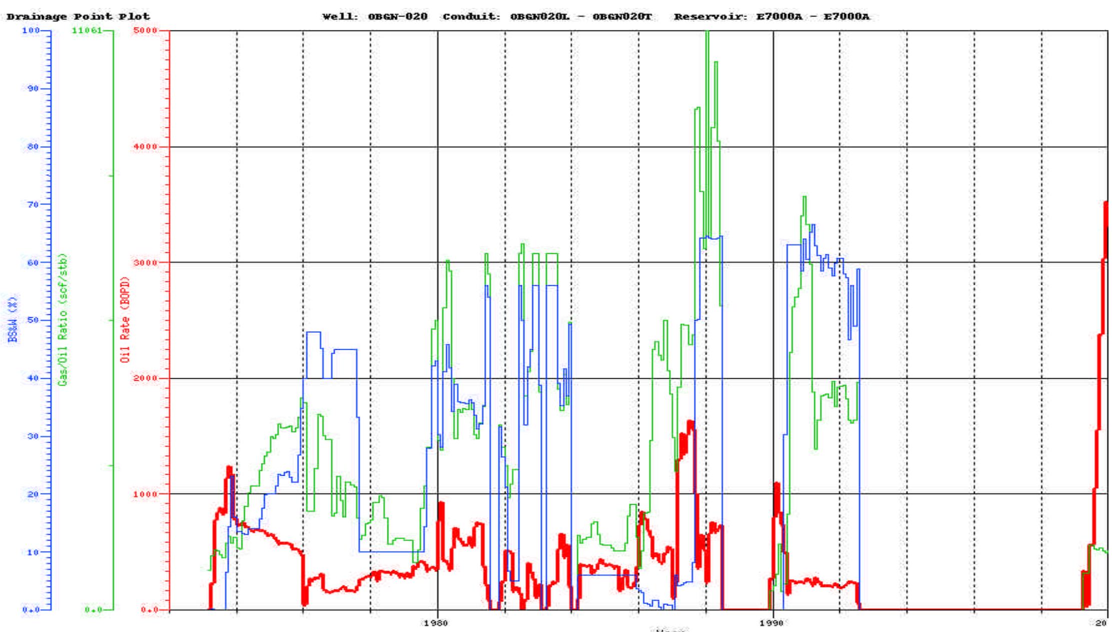


Figure 7. Obigbo North 20 Production Performance Plot

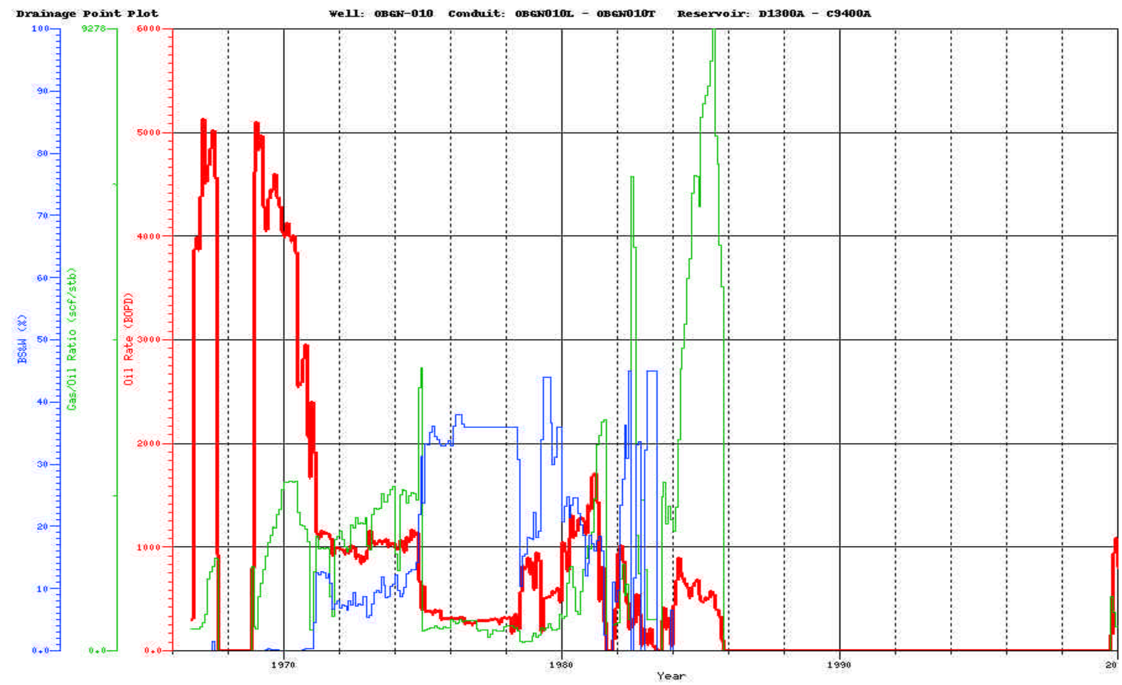


Figure 8. Obigbo North 10 Production Performance Plot

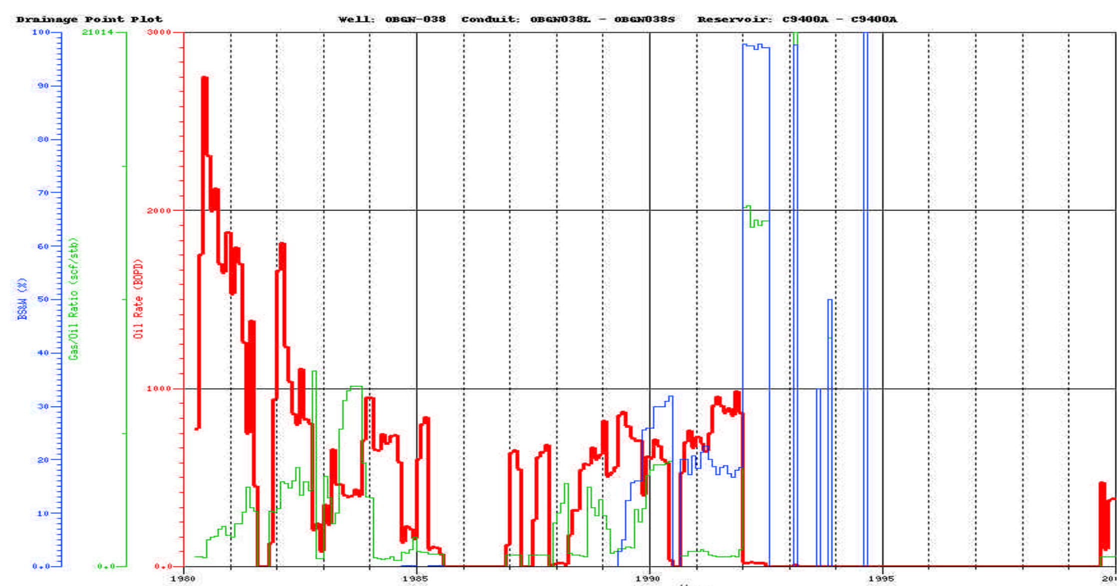


Figure 9. Obigbo North 38 Production Performance Plot

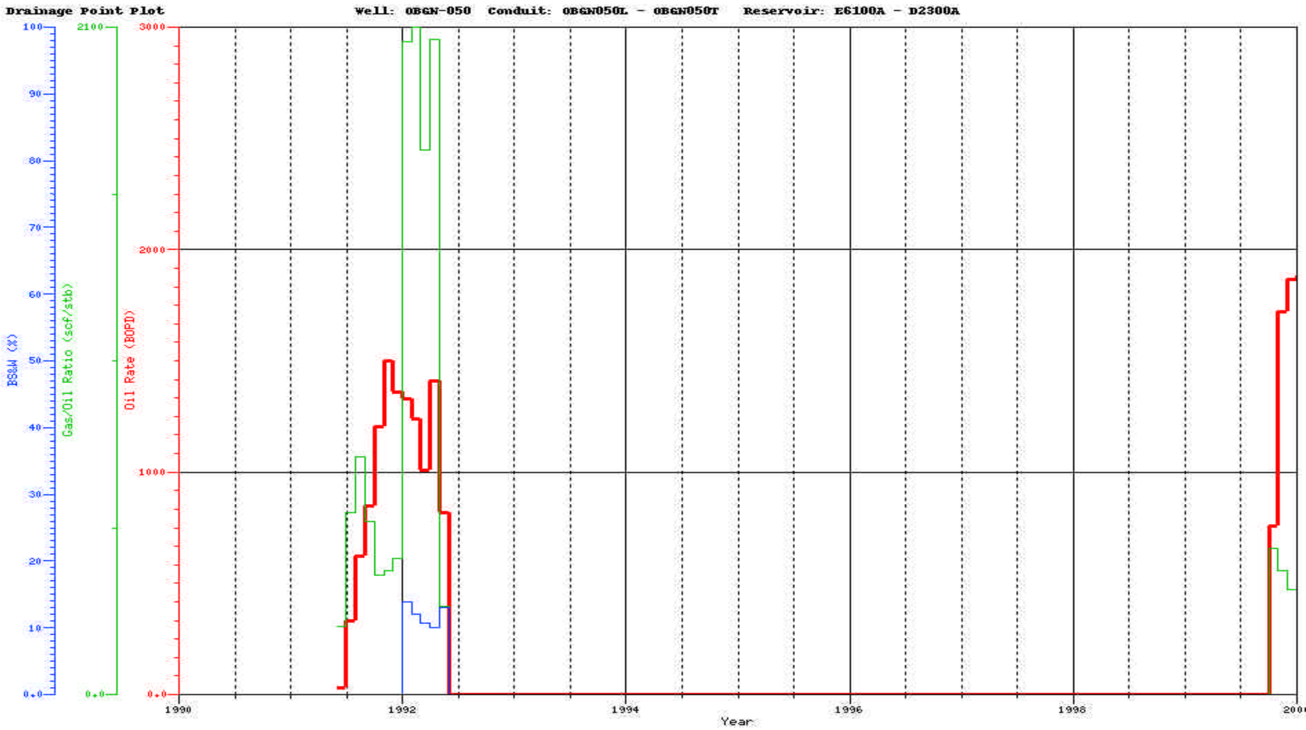


Figure 10. Obigbo North 50 Production Performance Plot

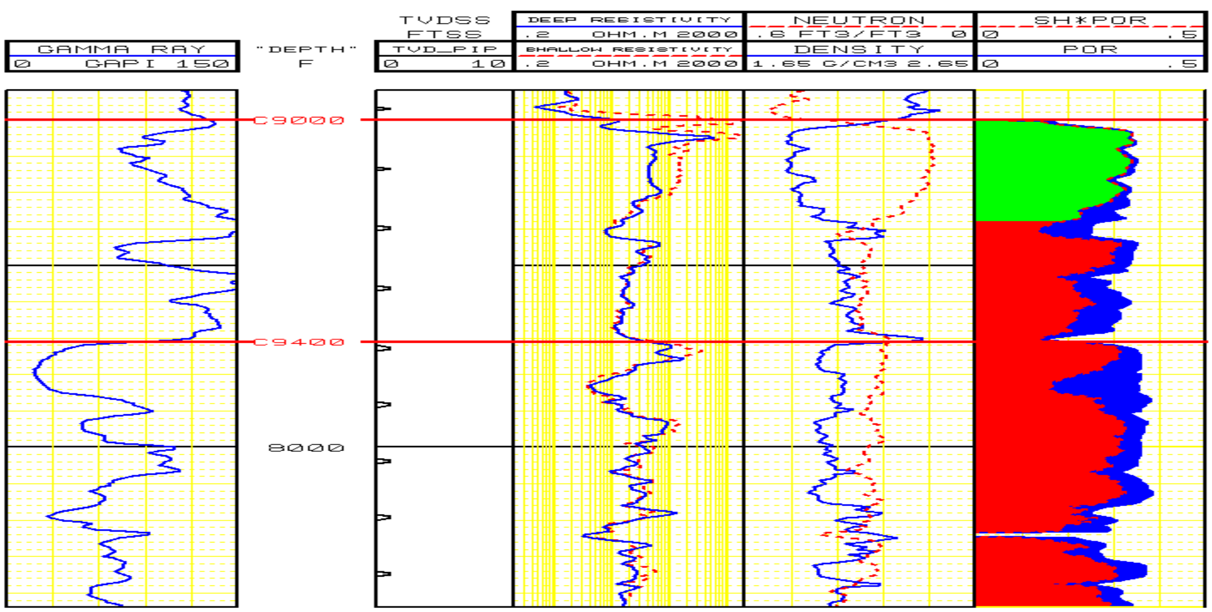


Figure 11. Obigbo North –38 deviated sidetrack results showing the differentially flushed interval

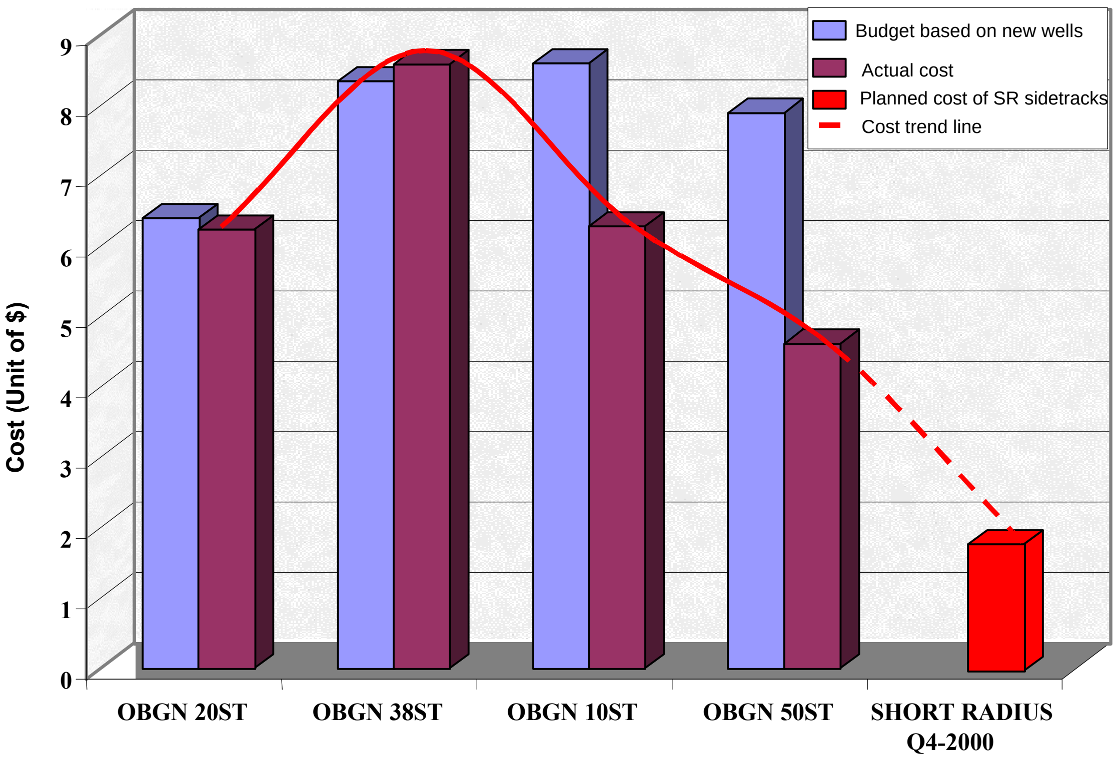


Figure 12. Cost Comparison showing budget for originally planned new wells, actual cost of replacement sidetracks, planned cost of new SR sidetracks and cost trend line

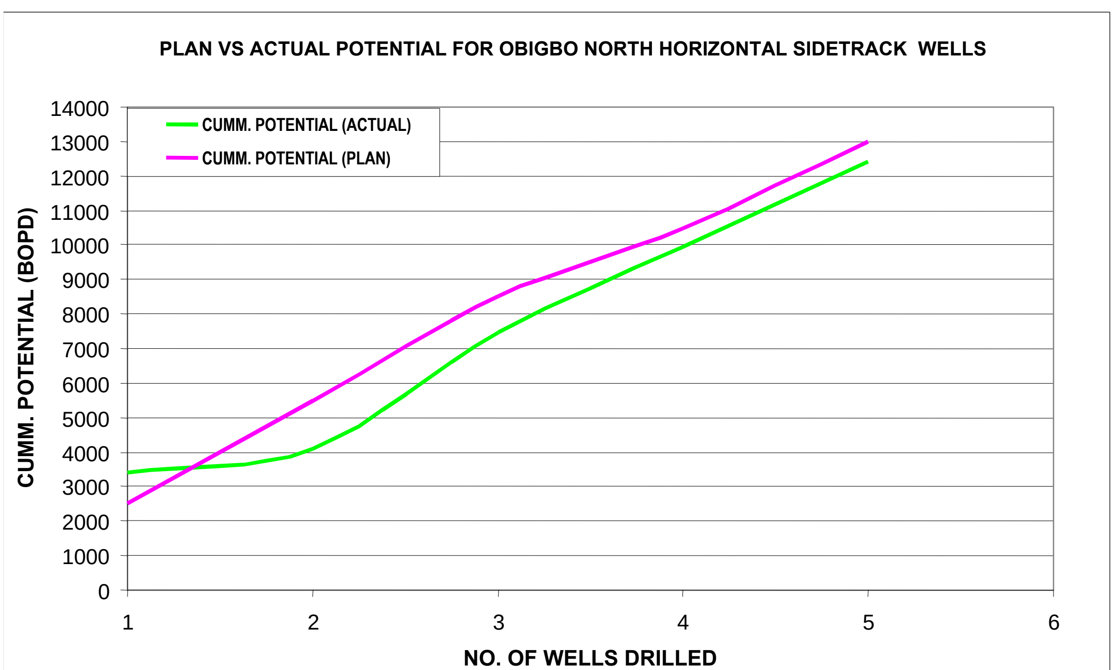


Figure 13. Plan vs Actual Potential Generated for Obigbo North Sidetracks.